Integrating Wireline Interpretation with Rock Properties to Better Determine Controls on the Occurrence of Reservoir Sand in Pohokura Field, Taranaki Basin, New Zealand

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Abstract

This study of reservoir sands in two wells in the Eocene Mangahewa Formation Pohokura Field, New Zealand is designed to show how integrating field-scale information from FMI interpretation with existing core and rock property data helps in gaining a better understanding the reservoirs sands. Specifically, it aims to quantify controls on the behav- ior of the reservoir's porosity and permeability. In the Pohokura-1 well, lamination and cross lamination dips are pre-dominantly SE and NW and subparallel to Pohokura anticlinal structure. In contrast, dips of lamination in the Pohokura South-1 well show more polymodal trends. These differences in lamination trend indicate differences in sand body orientation, which under petrographic study translates to the sand bodies in each well experiencing different depositional or tectonic histories. There are different sources of sediment supply and hence rock type due to different paleocurrent directions (as indicated by differences in cross lamination directions). Depositional environ-ments, (not diagenesis) play a fundamental role in determining reservoir quality as they control the character of the original pore network in the newly deposited sediments. Massive Sandstone lithofacies (as defined in FMI) is seen to form the best quality reser- voir where muddy lamination and bioturbation are seen to be detrimental to the reservoir quality. Overall, each of the documented diagenetic factors shows a damaging effect on the reservoir quality, but grain size and sorting dominate. Subsequent compaction and cementation are more critical post depositional effects compared to authigenic clay content and grain dissolution. There is a positive relationship between porosity-permeability and total quartz cement (levels <6% quartz overgrowth) as it sets up a stable grain framework that resists compaction. Beyond 6%, higher amounts of quartz overgrowth cement are detrimental as the cement is now present in sufficient pore volumes to occlude pore throats and lower permeability. In conclusion, differences in sand body geometry and probably different sources of sediment supply, together with textural, compositional and diagenetic variations between wells result in differences in reservoir quality. Pohokura-1 has a relatively better reservoir quality than Pohokura South-1 as the reservoir sand is coarser grained, and more quartzose dominant. In contrast, reservoir sands in Pohokura South-1 are finer-grained and more diagenetically active due to inherently higher feldspar and lithic contents.

Keywords: FMI, Petrography, Reservoir quality, Pohokura, Taranaki

1. Introduction

This research project focuses on Pohokura Field, Taranaki Basin, New Zealand. A total of 2 wells were studied and compared in this study; the offshore vertical well Pohokura-1 (POH-01) and the onshore deviated Pohokura South-1 (POS-01) well.

Taranaki Basin as a whole has complicated morphology and this leads to multiplicity of hydrocarbon plays, which are mostly structural in nature. Major structural phases in the basin occurred from Late Cretaceous and throughout Paleogene and the basin had infilled with sediments by Neogene time. The geological age of the reservoir in Pohokura field is Middle and Late Eocene. The play type in the Pohokura field is an inversion structure. The reservoir is made up of mainly transgressive marginal marine sands in an inverted anticline. The anticline is a result of crustal shortening during the Miocene when various sub-basins in the eastern and southern parts of Taranaki Basin were uplifted and inverted, causing reactivation and reversal of movement along many of basin's extensional faults (Crown Minerals, 2001). The complex sedimentary and tectonic history of Taranaki Basin (Figure 1) results in its current composite morphology and includes elements that have been in place since the mid-Cretaceous. Basin evolution begins with early rift-drift events that were later overprinted by Neogene convergent margin-related tectonics (King and Thrasher, 1992). The Taranaki Basin evolved to the present stage after going through three evolutionary phases (Sykes et al., 2014).

The main reservoir target in Pohokura field is the Mangahewa Formation which is the primary focus of this study. This study was undertaken to see how well an integration of FMI with existing core and rock property data can help in better understanding the reservoir sands of Eocene-age, Kapuni Group, Mangahewa Formation, Taranaki Basin. It aims to extract information from the FMI that will be beneficial in understanding the reservoir behaviour and character at field-scale and outside zones with core. In addition, this study aims to understand and rank what factors influence the quality of the reservoir, especially the behaviour of the reservoir's porosity and permeability. Raw FMI, conventional wireline data, core photographs, photomicrograph, SEM photographs, and completion reports were the basic materials integrated in this research project.

2. Methodology

The research methodology is subdivided into image analysis interpretation and rock property study.

Lamination and cross-lamination dipping trends were extracted via image analysis interpretation. Conventional wireline logs such as GR, NEUT, DENS, and RESS logs were used alongside the image analysis to determine lithology and unusual features within strata (e.g. position of sand/Carbonate nodules). The relationship between each factor and its porosity and permeability were visualised via bivariate plots.

Integration of field-scale information from image analysis with their rock properties provides better understanding on the reservoir quality variations between the wells.

Based on the zonation of Gamma Ray (GR) (figure 2a & 2b), Pohokura-1 (POH-1) shows a better separation between sands and shales compared to Pohokura South-1 (POS-01). Zone 4 of Pohokura-1 (POH-01) shows lower GR values (figure 2a) compared to Pohokura South-1

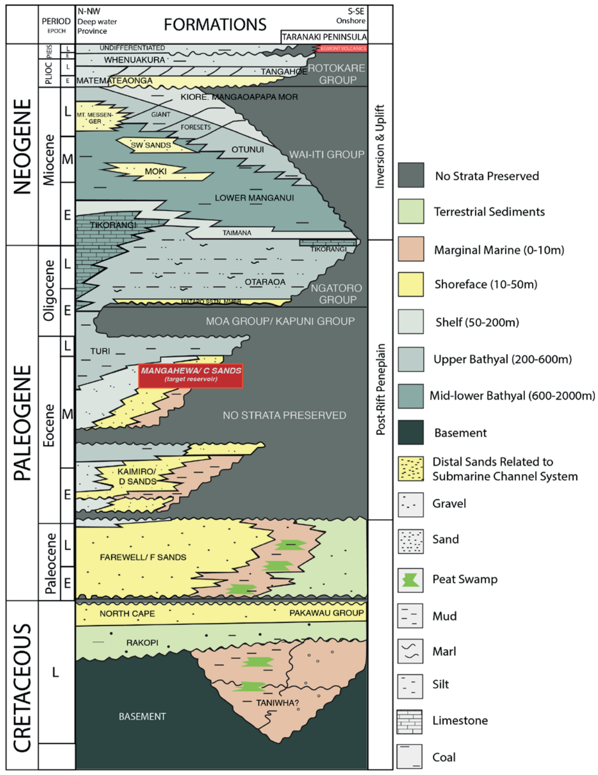

Figure 1: Generalized chrono-stratigraphy of Taranaki basin, modified after King and Thrasher (1996)

3. Results

3.1 Lithology Determination

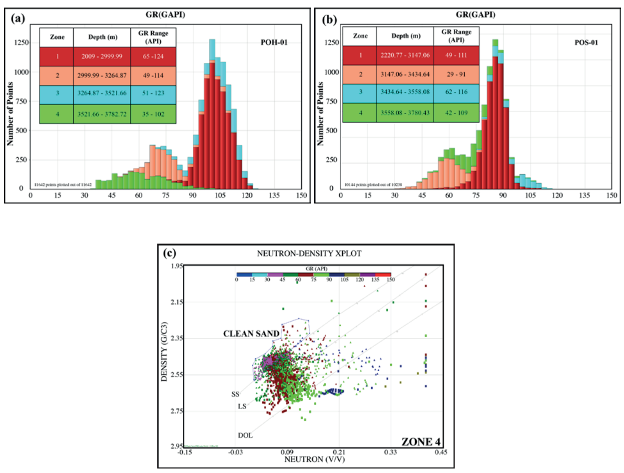

Figure 2: 4 zones were identified for each well from the zonation of GR log responses. (a) POH-01 have cleaner sand with lower mud content (indicated by lower GR) within the reservoir interval (zone 4) compared to (b) POS-01. N-D cross-plot (c) shows that clean, porous sand predominates in Zone 4.

(POS-01). Zone 4 of Pohokura-1 (POH-01) shows lower GR values (figure 2a) compared to Pohokura South-1 (POS-01) (figure 2b). This lower GR values in Pohokura-1 (POH-01) indicates that zone 4 of POH-01 has cleaner sand and less mud/shale compared POS-01. The higher GR values in zone 4 of POS-01 indicates that the sand body within that zone has higher mud content. The lower GR values correspond to lower mud/shale content in sand which results to a good reservoir quality.

3.2 FMI Interpretation Results

- **Lamination**

Laminations are bedding surfaces (less than 1 cm apart) found in sandstones that usually follows the orientation of bed boundary. These bedding surfaces separate the sand/shale beds,which provides information regarding the bedding orientation of the sand bodies. They were assumed to be deposited on a flat/nearly flat depositional surface, with any change in bedding orientation due to post-depositional tectonic movements or compaction.

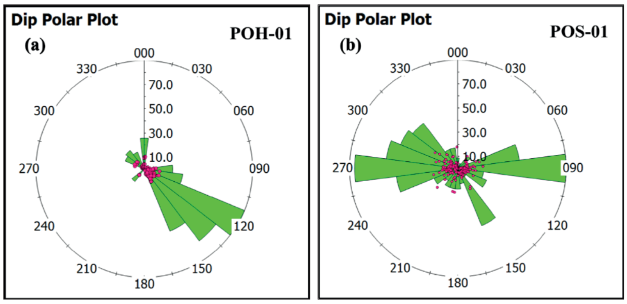

Figure 3: Dip-azimuth plot showing lamination in (a) POH-01 has a dominant SE-NW trend while (b) POS-01 has a polymodal trends which are E-W, NNE-SSW, and NNW

Differences in compiled lamination dip trends shown in figure 3 indicate differences in sand body orientation between the two wells. The differences in reservoir geometry (orientation) may leads to different porosity-permeability behaviours, thus affecting the quality of reservoir. In general, laminations in both wells show low angle dips (<10°) with some higher dips seen in Pohokura South-1 (POS-01) well.

- **Cross Lamination**

Cross-laminations are bedding units where laminae were deposited at an angle to the main bedding surface. These cross lamination generally represent sediments deposited in planar to trough bedforms and are very useful as compilations of their orientation in a set of FMI images can be used as paleo-current indicator.

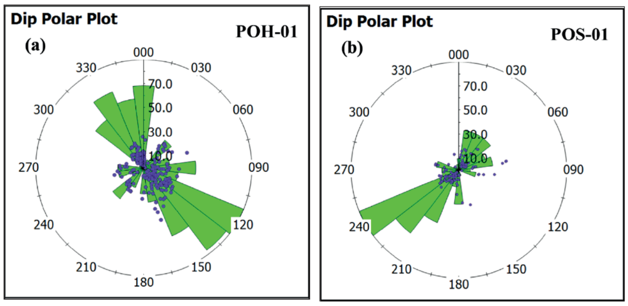

Figure 4: Dip-azimuth plot showing cross-lamination in (a) POH-01 has a dominant SE-NW trend with minor NE-NW trend while (b) POS-01 has a dominant SW and NE trend.

Differences in paleo-current trends between two wells, seen in figure 4, indicates that the differences in dip trend influence the porosity-permeability in reservoirs, which in turn could influence the reservoir quality. In addition, cross-lamination in (a) POH-01 has higher dips compared to (b) POS-01. This indicates that both wells may have different tectonic histories, where (a) POH-01 might have experienced more intense tectonic activity compared to (b) POS-01 which shows lower-angle dips.

- **Faults**

Faults were rare within zone 4 (reservoir interval) of both wells and were mostly found in zone 2 of both wells. This indicates that the tectonism had little influence within the reservoir intervals. The faults however show different orientations between two wells.

- **In situ stress indicator**

Borehole breakout (BB) and Drilling Induced Fracture (DIF) are orthogonal to each other and they indicate in-situ field stress orientations. Borehole breakouts are parallel to the minimum horizontal stress, while drilling induced fractures are parallel to the maximum horizontal stress. POH-01 maximum horizontal stress is orientated ENE-WSW (066°-246°) and minimum horizontal stress is orientated NNW-SSE (156°-336°). The POS-01 maximum horizontal stress is orientated E-W (086°-266°) and minimum horizontal stress is orientated N-S (172°-352°). The 20° differences in horizontal stress orientation between two wells may be related to the wellbore structural integrity.

- **Core to Image Analysis**

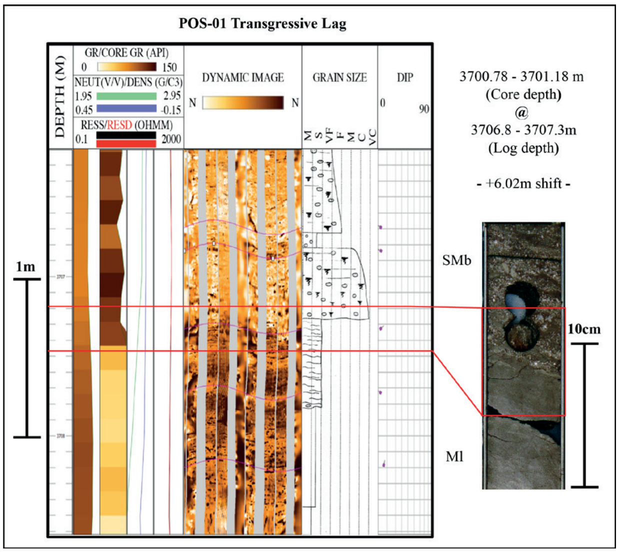

Figure 5: Transgressive lag noted in Pohokura South-1 core seen in the FMI image showing sharp boundaries, indicating changes between lithofacies from laminated Mudrock (Ml) to Mud-rich Bioturbated Sandstone (SMb). A good match seen after adepth shift of +6.02 m is applied. Increase in resistivity upwards (dark to light brown) likely indicate coarsening upwards. Lithofacies after Breare (2000). (1:10 scale)

There is a good match between geological features seen in the core and features seen in the FMI borehole images. Of all the lithofacies identified by Breare (Core Laboratories, 2000a ,2001), most of the lithofacies could be recognised in the borehole images, with varying levels of confidence and difficulty. For instance, Mud-dominated Bioturbated Sandstone (Msb) and Bioturbated Sandstone (Sb) was easily differentiated from Laminated Sandstone (Sl). However, it is harder to distinguished between Msb and Sb itself. The other lithofacies like Massive Sandstone (Sm), Granular laminated

Table 1: Example of geological features with a good depth match between cores and image log.

Geological features seen in cores	Core Depth (m)	Image Log Depth (m)	Core-to-log shift (m)
Sharp oundary between Massive Sandstone (Sm) and Rootlet Sandstone (Srt) @ POS-01	3702.88	3703.07	+6.12
Mud infilled horizontal burrow and vertical fracture @ POS-01	3732.18	3741.3	+7.22
Boundary between Bioturbated Sandstone (Sb) (above) and Cross laminated Sandstone (Sl) (bottom) @ POS-01	3747.9 – 33748.6	3755.2 – 3756	+7.35
Coal beds (C) interval @ POS-01	3747.9 – 33748.6	3755.2 – 3756	+7.35
Cemented Sandstone (Sc) within Bioturbated sandstone (Sb) @ POS-01	3692.04 - 3692.9	3698.8 - 3699.54	+6.76

Sandstone (Sgl) and laminated Mudrock (Ml) were distinguishable in the borehole images. Cemented Sandstone (Sc) was lithofacies independent as it occurs in both Bioturbated Sandstone (Sb) and Rootlet Sandstone (Srt). Some of the sharp boundaries between two lithofacies were recognised in the borehole images. For instance, the transgressive lag noted in POS-01 core was recognised in the FMI (Figure 5). Example of geological Features with a good depth match between cores and image log are summarised in Table 1.

3.3 Factors Controlling Reservoir Quality

- **Lithofacies**

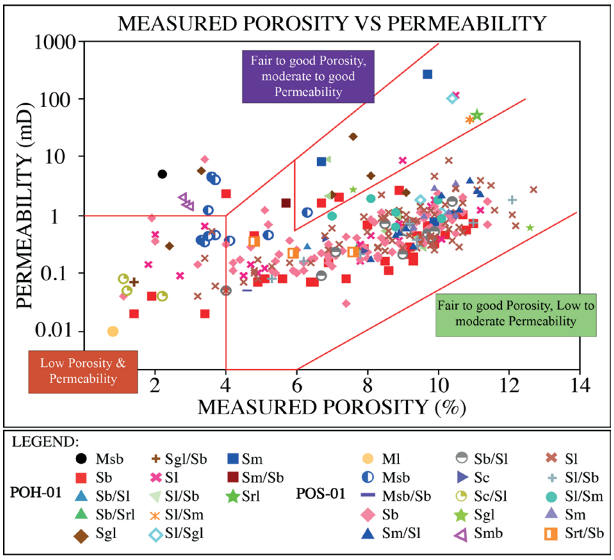

Figure 6: Plot of measured porosity vs horizontal permeability measured from core plugs for POH-01 and POS-01 well. Each core plug is masked with lithofacies defined by FMI interpretation.

Thirteen lithofacies are defined by texture and sedimentary characteristics. An overall linear positive trend is seen in figure 6 where permeability increases as the porosity increases This indicates that more well-connected pores become available as more pore space is created, thus leading to an increase in measured porosity and permeability. Three distinct poroperm groups that can be tied to: 1) lithofacies having fair to good porosity with moderate to good permeability, 2) lithofacies with fair to good porosity, with moderate to low permeability and 3) lithofacies with poor porosity and permeability. Lithofacies that shows the best porosity-permeability relationship is the Massive Sandstone (Sm) from Pohokura-1 (POH-01) well (averaging 9.7%, 260mD). The second best lithofacies is from Pohokura-1 (POH-01), the Laminated Sandstone (Sl) (10.5%,113mD) and the Granular Laminated Sandstone/laminated Sandstone (Sl/Sgl) (10.4%, 100mD). Bioturbated Sandstone (Sb), Mud-Dominated Bioturbated Sandstone (Msb) and Cemented Sandstone (Sc) each show an overall poorer poro-perm relationship.

Massive Sandstone (Sm) lithofacies having the best porosity-permeability relationship indicates zones with the best reservoir quality and this classification is viable outside the cored intervals. This better reservoir quality is likely due to the homogeneity of the sand body and its low mud content. The low mud content indicates less disturbance to the pore spaces within the sand body. This is because the occurrence of mud in sand body tends to fill the pore spaces and block pore throats, thus reducing the porosity and permeability. Laminated Sandstone (Sl) and Bioturbated Sandstone (Sb) both displays a good porosity-permeability relationship. However, they both show lower porosity-permeability values compared to the Massive Sandstone (Sm) lithofacies (Figure 6). This is due to higher content of mud in each respective lithofacies as compared to the Massive Sandstone (Sm). When comparing between the two, the Laminated Sandstone (Sl) shows a slightly better porosity-permeability relationship. This implies that the Laminated Sandstone (Sl) and Bioturbated Sandstone (Sb) lithofacies likely possess two different flow characteristics. In a sand body, bioturbation is more likely to create a more homogenous and thick unit while laminated (unbioturbated) units are more likely to be anisotropic and layered (figure 7). Differences in appearance FMI also indicates different kinds of dominant depositional process.

- **Facies**

Facies control the original pore system during sediment deposition and a sediments behaviour during deposition is highly influenced by the environment of deposition. In this study, the best reservoir quality is represented by channel facies in the upper shoreface, which has the highest permeability values. In contrast, the Lower shoreface facies, which was deposited in more distal setting, somewhat lower within the fair-weather wave base zone, displays poorer poro-perm values. This results from the overall lower bottom energy compared to the upper

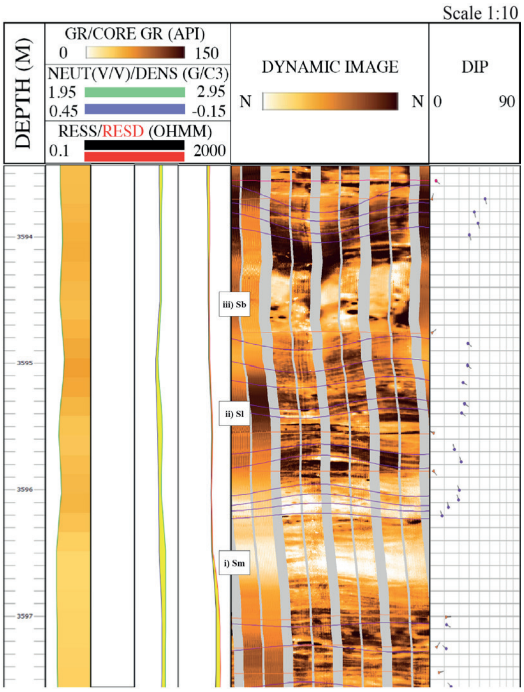

Figure 7: Massive Sandstone (i) display a homogeneity in sand body with low mud content. Bioturbated Sandstone (iii) appears as small burrow related patches distributed throughout sand body while laminated Sandstone (ii) appear to be more uniform or layered in a sand body. Different in lithofacies appears to influence the flow character of the fluids, thus impact the poro-perm relationship and the quality of the reservoir.

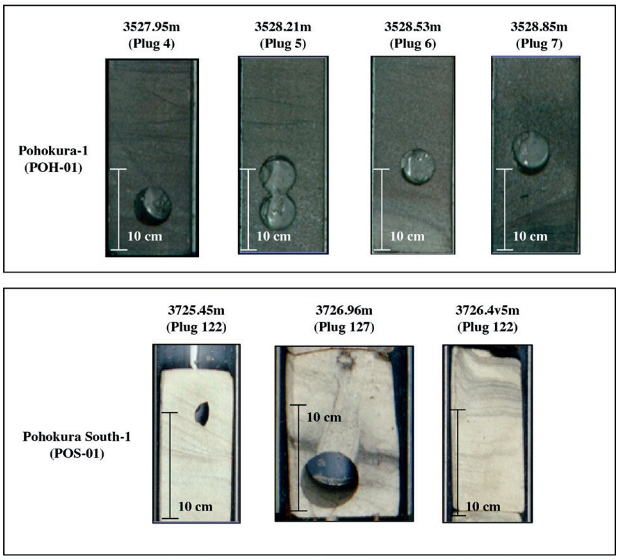

Figure 8: Core photographs of (a) POH-01 and (b) POS-01 indicating grain size in POH-01 is coarser grain compared to finer grain sizes in POS-01 core so explaining the higher permeability values. (Core photographs provided by New Zealand Database).

shoreface, thus depositing finer grains and muddier (poorly sorted) deposits.

- **Grain Size & Sorting**

The upper shoreface facies in Pohokura-1 (POH-01) displays higher permeability values, as compared to the Pohokura South01 (POH-01) well, indicating a better reservoir quality. These difference in porosity-permeability values within the same facies are due to distinctive sediment grain size spreads in each well (Figure 8).

The relationship between facies/lithofacies and reservoir quality are closely tied to grain size and degree of sorting. A coarse-grained sandstone mainly composed of stable and subrounded framework grains, such as quartz, will have much larger primary intergranular pore spaces than a fine-grained sandstone of similar composition. Larger grain sizes, with similar degrees of sorting, are associated with larger pore spaces between grain in POH-01. This facilitates fluid flow, which results in a more permeable sand body, thus promoting better reservoir quality than finer-grained, smaller pore spaces between grain, as seen in POS-01 sediments.

- **Authigenic Clay**

Pore filling authigenic kaolin is the most abundant authigenic clay mineral in both wells and it appears in several different morphological forms. Some of the authigenic kaolin minerals shows signs of illitisation, with rare occurence of well-crystallised pore-lining authigenic illite in both wells. Pore filling behavior is seen in kaolin minerals where the minerals tend to fill the intergranular pore spaces between grains. These pore-filling minerals can later dissolve and form secondary porosity. In contrast, pore lining behavior is seen in the illitic clays. These are filamentous clays with pore-bridging fabrics that reduce the intergranular pore space by forming coating around the grains framework. Grain-coating behavior tends to have more detrimental effects on poroperm compared to pore filling kaolin.

The amount and type of authigenic clay minerals formed can be related to the composition of the reservoir sand body. Based on the QFR plots (figure 9), POS-01 has a higher amount of feldspar and lithics compared to POH-01. These higher amounts of feldspar and lithics likely indicates that at the same burial depth (same temperature), sediments of POS-01 are more prone to diagenesis compared to POH-01, which contains higher amounts of quartz and lower amounts of feldspar and lithics. Higher amounts of feldspar and lithics in a sand body contributes to the higher amounts of authigenic clay. This is because the authigenic clay minerals form by feldspar decomposition or from the replacement of detrital mica. Therefore, a higher amount of feldspar and lithics has made POS-01 more diagenetically active, and this could be the contributing factors to the higher amount of authigenic clay, which decreases the quality of reservoir.

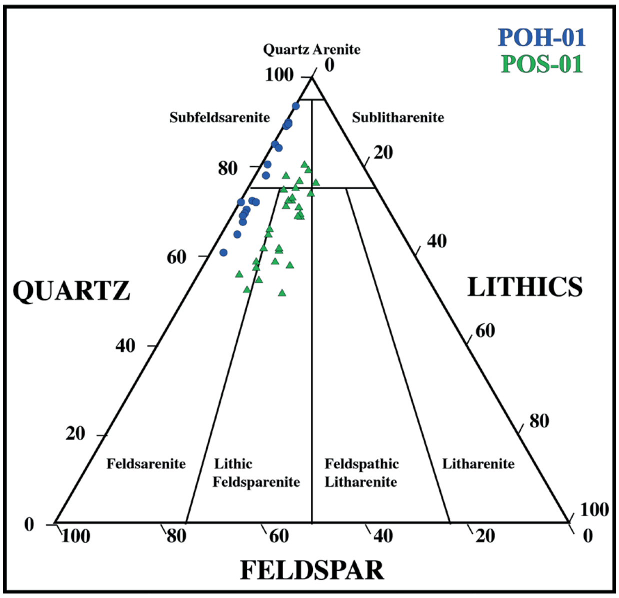

Figure 9: Sandstone classification complied from petrographic samples for POH-01 and POS-01 (modified from Higgs, 2001)

- **Cementation**

Cementation plays a major role in reducing porosity and permeability in sandstones. This can be seen in samples with localized pore filling siderite cements (figure 10 (a)) and dolomite cements (figure 10 (b)) having low permeability values, indicating poor reservoir quality. Two different trends were identified in a cross-plot between quartz overgrowth cements and poro-perm values (figure 10 (c)). Below 6% quartz overgrowth, growing quartz cement preserves the pores from being destroyed by inhibiting the compaction process, explaining the positive relationship between increasing quartz overgrowth with poro-perm spread. However, beyond 6%, quartz overgrowths start filling the intergranular pore, reducing the pore throat size thus lowering the poro-perm.

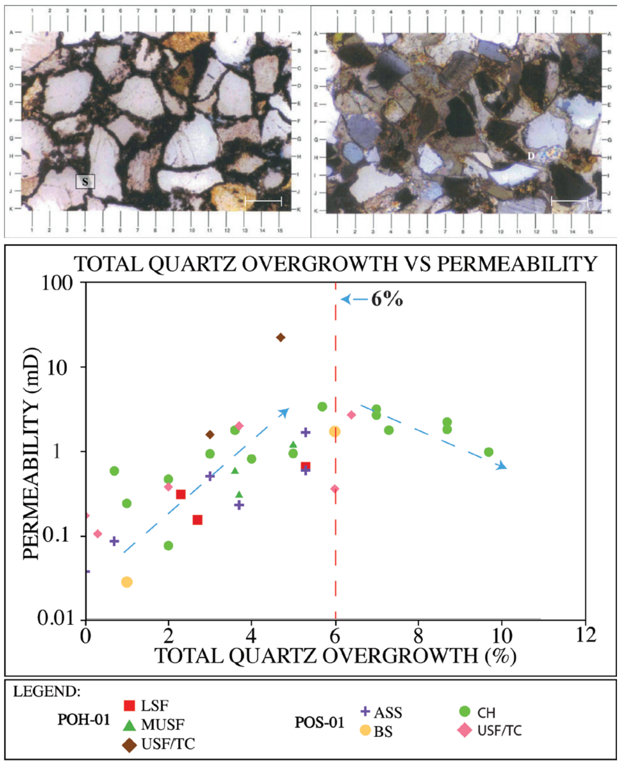

Figure 10: (a) Detrital grains surrounded by fine-grain lenticular siderite (S) cements, filling the intergranular pore spaces. No visible pore space remains. (POS-01 Plug 55, 3696.92m) (PPL, 200 µm). (b) Pervasive sparry dolomite (D) cements filling the intergranular pores, destroying visible pore space. (POS-01 Plug 42, 3692.18m) (X-Nicol, 200 µm). (c) Cross plots between total quartz overgrowth and Permeability for both wells coded by facies. Two distinct trends were seen with the 6% total quartz overgrowth cut-off value. (Photomicrographs provided by New Zealand Database)

- **Compaction**

In general, all samples taken from both wells display the effects of mechanical compaction, where the porosity is lost due to grains becoming closer packed. In addition, detrital grains in some samples display concavo-convex with slightly sutured grain contacts, indicating that some chemical compaction had also taken place at some point during diagenesis. Nevertheless, mechanical compaction plays the major role in porosity reduction in both wells compared to chemical compaction. POH-01 is seen to have experienced slightly more intense compaction due to its closely-packed grain fabric compared to grain relationships in POS-01 samples, which still retain visible intergranular porosity. This difference in compaction intensity can be due to a different burial history, diagenetic history, different sandstone compositions or tectonic activity.

4. Discussion

Integrating FMI interpretation as done in this study helps in creating a better understanding of the reservoir characteristics as it provides regional understanding of the reservoir characteristics. This is because petrographic study only provides information that is restricted to a certain interval (cored interval), so the results are more localized. Therefore, when the field-scale FMI information is coupled with the detailed reservoir scale (petrographic study) information, the combination provides a better understanding of the two and three-dimensional spread of reservoir characteristics, particularly of the porosity-permeability. Trends of lamination, cross-lamination, faults and fracture orientations are some examples of useful information that can be extracted from FMI interpretation.

Lamination trends are essential information as it can provide information regarding the sand body geometry. This can be seen in the different trends between POH-01 and POS-01 wells, where POH-01 shows dominant SE and NW dipping trends (figure 2.4) while POS-01 appears to show more polymodal trends (figure 2.5). POH-01 trends are subparallel to the Pohokura anticlinal structure orientation, which is oblique to POS-01, which trends subparallel to the paleocoastline (Horan, 2000, 2002). Differences in sand body orientation may indicate different depositional histories or tectonic histories experienced by each well, which led to the difference in porosity-permeability of the reservoir.

Cross lamination found within the sand bodies making up the reservoir sands acts as a paleocurrent indicator. POH-01 has dominant dip trends of NW and SE (figure 2.6), which is subparallel to the Pohokura Anticlinal structure. Sediment deposition within POH-01 is seen to be trending approximately perpendicular to NE-SW trending paleocoastline at the time of deposition. Meanwhile, POS-01 dip trends are dominantly SW and NE (figure 2.7) and oblique from POH-01 trends but subparallel to the paleocostline trend at the time of deposition. These different trends in cross lamination indicate different paleocurrent directions. This could indicate that the sources of sediment are different for POH-01 and POS-01 wells. Different source of sediments may lead to differences in compositions and in grain size of sediments during deposition, which in turn leads to different pore systems and porosity-permeability behaviors between the wells. In addition, differences in paleocurrent indicator also may suggest a different burial history or diagenesis style which also may result in different porosity-permeability behaviors seen in the two wells.

Integrating image analysis also provides a better understanding on how a particular lithofacies can affect the porosity-permeability of the reservoir sands. Better visualization of bioturbation or cementation can be seen in image analysis. For instance, in image logs, the effect on bioturbation in Bioturbated Sandstone (Sb) lithofacies can be clearly seen. In addition, the intensity of bioturbation at a certain interval can be estimated from borehole images. Borehole images also helps in understanding how Laminated Sandstone (Sl) and Bioturbated Sandstone (Sb) lithofacies affect the pore fluid flow in the reservoir sands. Under image logs, Bioturbated sandstone (Sb) appears as patches (usually dark patches as it filled with muddy burrows) while laminated sandstone (Sl) appears as layers. Differences in mud distribution within the porous sand body seen in borehole image provides an understanding on why these two lithofacies have different porosity-permeability values. Bioturbated Sandstone (Sb) is seen to have more detrimental effects of bioturbation in the porosity-permeability spreads of the sands with consistently lower poroperm values compared to Laminated Sandstone (Sl).

This richness of information from FMI provides a better understanding on how a cert lithofacies has that certain porosity-permeability values. This type of visualization cannot be done without the help from the borehole images. Combination of core photographs and borehole images provides better understanding on how bioturbation affects the porosity-permeability of the reservoir sands. Furthermore, borehole images sometimes help in improving a core description, which was previously done with the naked eye. This is due to borehole images provides higher resolution images compared to core photographs. For instance, in POH-01, interval 3527.3-3527.6m were described as Sl/Sm but lamination was seen throughout the interval. This indicates that higher resolution of borehole images may improve the lithofacies described earlier. Nevertheless, not all lithofacies described from the core description can be recognized in the borehole image logs. Mud-dominated bioturbated sandstone (Msb) and Bioturbated Sandstone (Sb), Laminated Sandstone (Sl) and Granular laminated Sandstone (Sgl) described in the core description cannot be distinguished from each other as they all appear very similar to each other in borehole image logs.

As a whole, each of the diagenetic factors shows a detrimental effect on the reservoir quality. An exception is seen in quartz overgrowths where below 6% total quartz grain display an increase in porosity-permeability values as the total quartz increase. This is explained by how the growing quartz grain preserves the pore spaces from being destroyed during compaction. However, as the total quartz cement exceeds 6%, these cements becomes detrimental to the reservoir quality as quartz cement, while still resisting compaction, now starts to be present is sufficient volumes in the pore spaces to destroying the intergranular connections and in the end reduces the porosity-permeability of the sands. No clear relationship between lithofacies/facies and porosity-permeability values indicates that elevated porosity-permeability levels are not restricted to a certain lithofacies/facies, however, a good quality reservoir do favor a certain type of lithofacies and facies. For this study, USF/TC and Massive sandstone (Sm) units are most likely to have best reservoir quality

5. Conclusion

Altogether, differences in sand body geometry and probable influence of different sources of sediment supply, together with textural, compositional and diagenetic variations between wells, results in differences in reservoir quality. The coarser grained, more quartz-dominant sands from Pohokura-1 having a relatively better reservoir quality compared to finer-grain, more diagenetically-active higher feldspar and lithic content sands of Pohokura South-1.

Based on work done this study, it can be concluded that:

1) Integrating field-scale understanding from FMI interpretation with the reservoir rock properties provides a better understanding of the porosity-permeability behaviors of reservoir sands.

2) Differences in reservoir sand body geometry and different paleocurrent directions influence the porosity and permeability spreads in the reservoir sands

3) Higher image resolution from FMI helps in gaining a better understanding how particular facies affect the porosity and permeability behavior of the reservoir sands.

4) The available cores, as rock controls, provides a higher degree of confidence in interpreting the non-cored interval using FMI image logs.

5) Depositional environment plays a vital role in the reservoir quality as exerts a dominant influence on the original pore network of the newly deposited sediments and this is largely retained in the study area

6) Massive Sandstone lithofacies (Sm) forms the best quality reservoir, followed by the laminated Sandstone and Bioturbated Sandstone. High prevalence of lamination and bioturbation are detrimental to the reservoir quality.

7) The quality of the reservoirs is influenced by grain size, authigenic clay mineral content, cementation, and compaction

8) High volumes of authigenic clay minerals, cementation, and compaction exert detrimental effects on the reservoir quality

9) Overall, the coarser grain, quartz dominate reservoir sands of Pohokura-1 (POH-01) have better reservoir quality as compared to finer grain, more diagenetically active Pohokura South-1 (POS-01) sands.

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7. References

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